

PATENT APPLICATION

METHODS AND APPARATUS FOR REMOTE REAL TIME OIL FIELD MANAGEMENT

Inventors:

RAMAKRISHNAN, Terizhandur S., a citizen of the United States, residing at 29 Oak Ridge Road, Bethel, Connecticut 06801-1154;

THAMBYNAYAGAM, Raj Kumar Michael, a citizen of the United States, residing at 159 North Street, Ridgefield, Connecticut 08677;

TILKE, Peter Gerhard., a citizen of the United States, residing at 13 Rowland Lane, Ridgefield, Connecticut 06877; and

RAGHURAMAN, Bhavani, a citizen of the United States, residing at 12 Indian Rock Place, Wilton, Connecticut 06897.

Assignee: SCHLUMBERGER TECHNOLOGY CORPORATION
with offices at:
Old Quarry Road
Ridgefield, CT 06877-4108
Incorporated in the State of Texas

Correspondence Address:

SCHLUMBERGER-DOLL RESEARCH
Intellectual Property Law Department
Old Quarry Road
Ridgefield, CT 06877-4108

1 METHODS AND APPARATUS FOR REMOTE REAL TIME OIL FIELD MANAGEMENT

2
3 BACKGROUND OF THE INVENTION
4

5 1. Field of the Invention

6 The invention relates to methods and apparatus for oil field
7 management. More particularly, the invention relates to methods
8 and apparatus for remotely monitoring oil field reservoir data in
9 real time.

10
11 2. State of the Art

12 During the production of fluids such as hydrocarbons and/or
13 gas from an underground reservoir, it is important to determine
14 the development and behavior of the reservoir to allow production
15 to be controlled and optimized and also to foresee changes which
16 will affect the reservoir in order to take appropriate corrective
17 measures.

18
19 Methods and devices for determining the behavior of
20 underground reservoirs, for example by measuring the pressure of
21 fluids, are well known in the prior art. It is known to locate a
22 pressure gauge at the bottom of a production well and connect it
23 to the surface by a cable or other communication means. It is
24 also known to generate a pressure pulse in one well and measure

1 the change in pressure in a nearby well. With these methods, it
2 is necessary to carry out extensive model fitting and complex
3 calculations to determine the behavior and properties of the
4 reservoir.

5
6 U.S. Patent Number 5,467,823 discloses methods and apparatus
7 for long term monitoring of reservoirs. The methods include
8 lowering a sensor into a well to a depth level corresponding to
9 the reservoir, fixedly positioning the sensor while isolating the
10 section of the well where the sensor is located from the rest of
11 the well, and providing fluid communication between the sensor and
12 the reservoir. The apparatus include at least one sensor
13 responsive to a property (e.g. pressure) of fluids and means for
14 perforating a cement layer to provide a channel for fluid
15 communication between the sensor and the reservoir. The methods
16 and apparatus provide a long term installation for monitoring an
17 underground fluid reservoir traversed by at least one well.

18
19 All of the known methods and apparatus for monitoring
20 reservoirs require that the data be analyzed by human experts in
21 order to interpret it. This analysis typically occurs on site,
22 requiring human experts to travel from one site to another in
23 order to interpret oil field data. It would clearly be

1 advantageous to allow human experts to access this data remotely,
2 thereby saving otherwise wasted travel time.

3 Communication systems are known in the art whereby oil field
4 data is transmitted to a central location for analysis. For
5 example, the WELLWATCHER™ system from Schlumberger continuously
6 transmits (via satellite) subsurface sensor data to a centrally
7 located analysis and data repository center. Although the
8 WELLWATCHER™ system provides many advantages, there remain several
9 disadvantages of oil field data analysis which are not addressed
10 by the WELLWATCHER™ system. One apparent disadvantage is that the
11 "central location" may not be conveniently located for all of the
12 human experts involved with a particular oil field. Another, less
13 apparent, disadvantage is that there is too much raw data.

14
15 One of the disadvantages of oil field data analysis that has
16 gone largely unaddressed in the art is that most of the analyzed
17 data provides no important information, yet requires as much
18 effort to interpret as the data which provides important
19 information. This is to say that, more often than not, the
20 analyzed data indicates that the oil field is producing at an
21 efficient rate and there have been no changes in the reservoir
22 requiring corrective action. As a result, human experts analyzing
23 oil field data spend most of their time analyzing data that
24 provide no new information about the reservoir.

SUMMARY OF THE INVENTION

It is therefore an object of the invention to provide methods and apparatus for remote real time oil field management.

It is also an object of the invention to provide methods and apparatus for remote real time oil field management whereby oil field data can be accessed by human experts from virtually anywhere in the world.

It is another object of the invention to provide methods and apparatus for remote real time oil field management whereby oil field data need not be constantly analyzed in order to detect an anomaly.

It is still another object of the invention to provide methods and apparatus for remote real time oil field management whereby human experts only need to analyze oil field data in the event of an anomaly.

In accord with these objects which will be discussed in detail below, the methods of the present invention include installing oil field sensors in a conventional manner, coupling the sensors to a local CPU having memory, programming the CPU for

1 data collection and data analysis, providing a central web server
2 coupled to the Internet, and coupling local oil field CPUs to the
3 web server. According to one aspect of the invention, human
4 experts are permitted to access oil field data in real time via
5 the Internet by connecting to the web server and requesting data
6 for a particular oil field. According to another aspect of the
7 invention, the local CPUs provide different levels of data to the
8 web server. The web server provides the option to view raw data,
9 partially analyzed data, or fully analyzed data. According to
10 another aspect of the invention, the local CPUs are programmed
11 with parameters for analyzing the data and automatically
12 determining the presence of anomalies. Upon detecting the
13 occurrence of an anomaly, the local CPUs are programmed to notify
14 one or more human experts by email, pager, telephone, etc. If no
15 human expert responds to the notification within a programmed
16 period of time, the local CPU automatically takes a programmed
17 corrective action.

18
19 Preferred aspects of the invention include: storing data
20 differently according to the age of the data, e.g. finely sampled
21 data is stored for recently acquired data and older data is more
22 sparsely sampled. According to a presently preferred embodiment,
23 data is automatically analyzed using one or more algorithms
24 including "bound check", "trend check", "function check",

1 "correlation check", and "covariance check". An exemplary
2 "correlation check" is provided which utilizes signal processing
3 methods without utilizing an underlying model of the reservoir.
4

5 Additional objects and advantages of the invention will
6 become apparent to those skilled in the art upon reference to the
7 detailed description taken in conjunction with the provided
8 figures.
9

10 BRIEF DESCRIPTION OF THE DRAWINGS

11
12 Figure 1 is a simplified schematic block diagram of
13 components of the invention installed at an oil field;
14

15 Figure 2 is an exemplary graph of flowrate of pulsing in a
16 first active well over a period of time;
17

18 Figure 3 is an exemplary graph of flowrate of pulsing in a
19 third active well located about 40 meters from the first well over
20 a period of time;
21

22 Figure 4 is an exemplary graph of pressure in the first well
23 over a period of time;
24

1 Figure 5 is an exemplary graph of pressure over a period of
2 time in a second passive observation well which is located about
3 40 meters from the first well and about 80 meters from the third
4 well;

5
6 Figure 6 is an exemplary graph of pressure in the third well
7 over a period of time;

8
9 Figure 7 is an exemplary graph of differentiated pressure in
10 the second well over a period of time;

11
12 Figure 8 is an exemplary graph of the correlation function of
13 differentiated flow in the first well with the differentiated
14 pressure in the second well;

15
16 Figure 9 is an exemplary graph of the correlation function of
17 differentiated pressure in the first well with the differentiated
18 pressure in the second well;

19
20 Figure 10 is an exemplary graph of the correlation function
21 of windowed differentials pressure between the second well and the
22 third well; and

23

1 Figure 11 is an exemplary graph of the correlation function
2 of windowed differentials pressure between the first well and the
3 third well.

4
5 DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS
6

7 An apparatus for the remote, real time monitoring of an oil
8 field includes the components shown in Figure 1 which are referred
9 to as "e-well components" 10. The "e-well components" 10 include
10 one or more sensors 12 which are installed in the oil field in a
11 conventional manner. The sensors 12 (where analog) are coupled
12 via an analog-to-digital converter 14 to a CPU 16 which is
13 provided with RAM 18 and disk storage 20. According to a
14 presently preferred embodiment, a time synchronizer 21 is also
15 provided. The time synchronizer preferably includes algorithms to
16 time synchronize all of the data acquisition. According to one
17 aspect of the invention, the e-well components 10 are coupled to a
18 web server 24 which is preferably located at a central location
19 remote to the oil field. According to another aspect of the
20 invention, the e-well components are provided with a plurality of
21 program modules 26. These modules preferably include an analysis
22 module 26a, an alarm/messaging module 26b, an acknowledgement
23 module 26c, a controller module 26d, and an event logger module
24 26e. According to still another aspect of the invention, the e-

1 well components 10 also include a digital to analog interface 28
2 for controlling oil field equipment as described in more detail
3 below with reference to the acknowledge module 26c and the control
4 module 26d. According to a presently preferred embodiment, the e-
5 well components 10 are also provided with a direct access
6 communications link 30 so that the components may be accessed,
7 under certain circumstances, without going through the web server
8 24. The communications link 30 is preferably a direct link to the
9 Internet and is accessed via an IP address. The e-well components
10 10 shown in Figure 1 may be replicated for each well in an oil
11 field or may service more than one well in the oil field.
12

13 From the foregoing, those skilled in the art will appreciate
14 that the CPU 16 acquires data from the sensors 12 and stores the
15 data in the data storage 20 and also runs the program modules 26.
16 According to the presently preferred embodiment, archival data
17 stored in data storage 20 is compressed. Recently acquired data
18 are left uncompressed and are also maintained in RAM 18 for rapid
19 access and analysis.
20

21 For purposes of illustration, K wells are serviced by the
22 components 10. Each well has sensors which provide M classes of
23 data points at N locations. Although M and N may be different for
24 each well, for illustration these may be considered as being

1 maximum values. Each measurement collected by the e-well
2 components is designated $P_{ij}^{(k,l)}$ where k is the well ID, i is the
3 class of measurement (e.g., formation pressure, wellbore pressure,
4 temperature, voltage, etc.), j is the location in the well, and l
5 is the datapoint (point number for the data set). Data are
6 acquired over an interval $\delta_{ij}^{(k,l)}$. For simplicity, it is assumed that
7 δ is the same for each well. For every well k , each measurement
8 $P^{(k)}$ is an array of dimensions $M \times N$. Assuming that each measurement
9 requires four bytes, each well will require $4MN$ bytes of storage
10 for each time point. Taking one sample per minute, $MN \times 172$
11 Kilobytes memory is required for one month of data. According to
12 a presently preferred embodiment of the invention, as data ages,
13 it is decimated by several degrees. For example, data which is
14 more than a year old is compressed to a first level; data which is
15 more than two years old is compressed to a second level, etc.
16 However, the invention contemplates that data compression is only
17 used for well-site storage and that uncompressed data is
18 periodically uploaded to and stored at a remote host.

19
20 The presently preferred data compression scheme is based on
21 the techniques disclosed in Ramakrishnan, T.S. and Kuchek, F.,
22 Testing and Interpretation of Injection Wells Using Rate and
23 Pressure Data, SPE Formation Eval., 9:228-236 (1994), the complete
24 disclosure of which is hereby incorporated by reference herein.

1 According to this technique, points which show significant change
 2 while not being within the tolerance range of linear data fitting
 3 are chosen to be preserved. Data are stored in terms of straight
 4 lines between preserved data points. Thus, for a first level of
 5 compression, the preserved data can be expressed as shown in
 6 Equation 1 where b is the intercept, m is the slope, and t is a
 7 value consistent with Equation 2.

$$P_{ij}^{(k,1)}(l) = b_{ij}^{(k,1)}(l) + m_{ij}^{(k,1)}(l)t \quad (1)$$

$$\forall t_{ij}^{(k,1)}(l-1) \leq t \leq t_{ij}^{(k,1)}(l) \quad (2)$$

13 As shown in Equation 2, t is a number which is less than or equal
 14 to $t_{ij}^{(k,1)}(l)$, the preserved nodes after decimation, but greater than or
 15 equal to all of the nodes. As data is to be more compressed, more
 16 data is discarded. For example, decimation implies discarding one
 17 datum out of every 10. For greater compression, more data is
 18 discarded.

19
 20 As mentioned above, according to the presently preferred
 21 embodiment, the CPU 16 uses analysis program modules 26a to
 22 analyze the data acquired via the sensors 12 and provide the
 23 results of the analyses to the web server 24. Furthermore, the
 24 analysis results are used by the alarm/message program modules 26b

1 to provide immediate notification in the event that an unusual
2 event is detected. The presently preferred analysis modules
3 include bound check, trend check, function check, correlation
4 check, covariance check, and data acquisition frequency check.

5
6 Under the bound check analysis, bounds are specified for
7 various variables such as pressure, temperature, watercut,
8 flowrates, etc. If a variable falls outside of bounds, an
9 alarm/message is triggered as described in more detail below with
10 reference to the alarm/message module 26b. Examples of
11 alarm/message triggering events include: pressure dropping below
12 the bubble point in a production well, watercut increasing
13 suddenly, temperature changing dramatically, etc.

14
15 Under the trend check analysis, data is compared to a
16 specified band from point to point, e.g. historical trends based
17 on the archived data discussed above. Those skilled in the art
18 will appreciate that the data compression process described above
19 is itself a trend checker. If the trend is outside the norm, an
20 alarm/message is triggered as described in more detail below with
21 reference to the alarm/message module 26b. An example of an
22 alarm/message triggering trend event is a rapid decline in flow
23 rate, even if the flow rate is within bounds.

1 Under the function check analysis, one or more functions of
2 the data is compared to a band or bounds. An example of a simple
3 function check analysis is where different sets of data are
4 compared to determine whether their sum or difference exceeds a
5 bound. More specific examples are: when the flow rates of
6 individual wells are within bounds but where the combined flow
7 rates exceeds surface capacity; when pressure in one layer differs
8 from pressure in another layer by more than a certain amount;
9 where water cut from one production stream is very different from
10 the water cut from another stream which is being mixed with it,
11 etc.

12
13 Under the correlation check analysis, data sets from one well
14 are compared to data sets from another well over time to determine
15 characteristic signal propagation between two or more wells. An
16 example of a correlation check is comparing, over time, periodic
17 pulsing in one well with changes in pressure in another nearby
18 well. A specific presently preferred embodiment of a correlation
19 check is described in more detail below with reference to Figures
20 2-11.

21
22 Under data acquisition frequency check analysis, the
23 frequency of data acquisition from different sensors is compared

1 to set values. Anomalies may be indicative of a data acquisition
2 unit failure or missing data periods, etc. In such a case, an
3 alarm/message may be triggered as described in more detail below
4 with reference to the alarm/message module 26b.

5
6 Additional computations for the covariance of measurements
7 and their time evolution are contemplated by the invention.
8 Although Figure 1 shows analyses performed at the e-well
9 components site with the results being forwarded to the web
10 server, complex computations which would tax the CPU 16 are
11 preferably performed by the web server CPU. In such a case, the
12 e-well components will transmit the appropriate data sets to the
13 web server and the web server will perform the analysis and issue
14 alarms/messages in response thereto.

15
16 The alarm/message program module 26b receives signals from
17 the analysis modules 26a when anomalies are detected. According
18 to the presently preferred embodiment, the signals from the
19 analysis modules include an indication of the type of anomaly and
20 its severity. Depending on the severity of the anomaly, the
21 alarm/message module will immediately notify one or more human
22 experts by electronic mail, calling a pager, calling a telephone
23 number, activating an alarm, broadcasting an RF signal,
24 transmitting a signal to a satellite, transmitting a microwave.

1 signal, sending a signal via a LAN, or sending a signal via a WAN,
2 etc. The alarm/message module is preferably programmable as to
3 what action should be taken in response to particular anomalies,
4 etc. Some messages may require an acknowledgment if programmed to
5 do so.

6
7 The acknowledge module 26c keeps track of alarm/messages
8 which have been sent and which require an acknowledgment. The
9 acknowledge module also receives acknowledgements from human
10 experts who have received an alarm/message that requires an
11 acknowledgement. If no acknowledgement is received within a
12 programmed period of time, the acknowledge module may send a
13 signal to the alarm/message module whereafter higher priority
14 messages are generated or may send a signal to the controller
15 module 26d. Depending on the level of the warning message, the
16 type of anomaly, and the programming of the acknowledge module, a
17 signal will be sent to the controller module 26d if no
18 acknowledgement is received within a programmed period of time.

19 The controller module 26d is programmed to take automatic action
20 in response to signals from the acknowledge module which indicate
21 the anomaly and its severity. The controller module communicates
22 with analog devices at the well site(s) via the digital to analog
23 interface 28.

1 An example of the operations described above can be
2 appreciated where the analysis module determines that the water-
3 cut in a layer has exceeded a programmed value during a programmed
4 interval. If no acknowledgement is received for two
5 alarm/messages, the control module will perform a choke action to
6 throttle the flow from the offending layer. Action following
7 inaction is executed via the auto-action control-module.

8
9 According to the presently preferred embodiment, different
10 levels of alarm/messages may be sent requiring different human
11 action at different times and, in the absence of required human
12 action, automatic action taken at programmed times. Also
13 according to the presently preferred embodiment, when multiple
14 humans are notified of an alarm/message, all will be notified of
15 the resulting action, i.e. human intervention by person X, and/or
16 automatic control. It is also preferred that human experts be
17 given priority levels whereby a higher level expert can override
18 the actions of a lower level expert.

19
20 The alarm/message module may also be programmed to send
21 messages to other components in the system. For example, in the
22 event of a system restart where data acquisition is interrupted,
23 the alarm/message module may send a message to the CPU to increase

1 the rate of data collection in order to have a more accurate
2 correlation analysis of responses to the perturbation.

3
4 As described above, the controller module 26d initiates
5 automatic activity according to the program. The automatic
6 activities include, for example, throttling a section down upon
7 sensing an unacceptable water cut, preventing pressure from
8 dropping below a set value by throttling, increasing injection
9 rate for pressure support etc. The controller module may also
10 perform any of these kinds of actions in response to an email from
11 a remotely located expert.

12
13 The event logger module 26e keeps track of all planned and
14 unplanned events that occur in the field. Examples of planned
15 events include a build-up pressure test, well work-overs, change
16 in production rate, etc. An example of an unplanned event is a
17 pump failure that causes a well to shut down. The log of events
18 is provided to the analysis module 26a.

19
20 As mentioned above, one of the most robust analysis tools is
21 the correlation check. The following is an example of how the
22 correlation check is used in the context of pressure diffusion.
23 According to this example, three vertical line wells are located
24 in a laterally infinite formation. The second well is located 40

1 meters from the first well. The third well is located 40 meters
 2 from the first well and 80 meters from the second well. Each of
 3 the wells is capable of producing or injecting fluids. When fluid
 4 is injected into one of the wells, pressure response in the other
 5 wells is monitored. The rate schedule for fluid injection
 6 consists of arbitrary step changes to rates at time points. The
 7 step changes are allowed to grow to the new rate with a specified
 8 time-constant, i.e. pulses with exponential increase or decline.

9
 10 The step response function for pressure in well i due to flow
 11 in well j is given as G_{ij} . For all practical purposes one may
 12 superpose the result to give the pressure p_i in well i as shown in
 13 Equation 3 where t is time, τ is a dummy variable of integration,
 14 and q_j is the flow in well j . It is assumed that $q=0$ when $t=0$.

$$p_i = \sum_j \int_0^t G_{ij}(t-\tau) dq_j(\tau) \quad (3)$$

15
 16
 17
 18 The response function G_{ij} is shown in Equation (4) where E_1 is
 19 the exponential integral, ϕ is the porosity, μ is the shear
 20 viscosity, c is the compressibility, k is the permeability, t is
 21 the time, and r_{ij} is the distance from well i to j .

$$G_{ij}(t) = \frac{\mu}{4\pi kh} E_1 \left(\frac{\phi \mu c r_{ij}^2}{4kt} \right) \quad (4)$$

1 For computational purposes, random fluctuations in flow rates are
2 permitted in addition to the imposed steps. The calculations
3 discussed below were carried out with a 2% noise in rates.

4
5 In this example wells 1 and 3 are active wells and well 2 is
6 a passive or observation well. The permeability of the formation
7 is 100 md. The viscosity is 1 cp and the compressibility is
8 $4 \times 10^{-9} \text{ m}^2 \text{ N}^{-1}$. All the trial calculations included an initial step
9 on which were superimposed random fluctuations. When no
10 additional pulses were included it was found that it was difficult
11 to discern any influence of the random fluctuations. Physically,
12 if the transient time for diffusion is much larger than the time
13 scale of the fluctuations, then the time signature of the random
14 fluctuations is essentially lost at the remote points. Therefore
15 any inference that takes advantage of the propagation of the
16 random fluctuations is unlikely to be robust.

17
18 For the above-mentioned reason, experiments were performed
19 with periodic finite-amplitude pulsing of the active wells. The
20 pulsing sequence for wells 1 and 3 is shown in Figures 2 and 3,
21 respectively. Based on the proposition that the propagation will
22 be governed by pressure diffusion, whose characteristic time is
23 $r^2/(4D)$, where $D = k/\phi\mu c$ and r is the distance between the source
24 and the observation points, it is concluded that the correlation

1 time for pulse propagation should be expected to approximate this
2 value. Thus, periodic pulsing and a direct correlation function
3 plot will have a peak around the diffusion time-scale.
4

5 Correlation may be carried out in a number of different ways.
6 One method is to correlate the flow rate in an active well to the
7 pressure in an observation well. From a signal processing point
8 of view, this is a poor implementation. Because of the finite
9 amplitude background in both the pressure and the flowrate, the
10 correlation function does not indicate diffusion time-scales.
11 After several numerical experimentations a better procedure has
12 been discovered.
13

14 The preferred method includes providing or injecting the
15 active wells with a nearly constant rate; and performing a
16 periodic flowrate pulsing of the wells in a manner whereby the
17 active wells are not pulsed at the same time or with the same
18 amplitude. This ensures that the sources are not perfectly
19 correlated and the flowrate pulsing results in pressure
20 fluctuations in each well.
21

22 Since the background is predominantly uniform, it is possible
23 to differentiate both the flowrate and pressure data. If
24 necessary, the differentiation may be based on the decimated data,

1 to avoid strong noise influence. This was found this to be
2 unnecessary with 2% noise.

3
4 The differentiated data is composed of a nearly null
5 background and pulses. The pressure pulses are, however, diffused
6 according to the distance between the source and the observation
7 points. It is possible to window the differentiated data and
8 evaluate the correlation of two functions through well known FFT
9 methods. The cross-correlation may be done with flowrate and
10 pressure or pressure and pressure (all of them after
11 differentiation with respect to time). The latter has the
12 advantage that it is less noisy, and is easily measured.

13
14 According to the preferred method, a search is made for an
15 easily discernible peak in the correlation function. The location
16 of the peak automatically indicates the correlation time. The
17 value of the correlation time is converted to mobility and
18 displayed.

19
20 Because of the essentially signal processing nature of the
21 above-described method, the process is automated rather easily.
22 The novelty of the method lies in the conversion of the essential
23 physics of pressure propagation into a signal processing
24 algorithm.

The above-described method is illustrated with reference to the remaining Figures. For the flowrate pulsing shown in Figures 2 and 3, the pressure responses are shown in Figures 4-6. As shown, the response in the observation well 2 is sluggish. The differentiated pressure signal in well 2 is shown in Figure 7 and is clearly noisy. Nevertheless, the intentional pulsing dominates over the noise spikes.

The correlation function between dq/dt in well 1 and dp/dt in well 2 is shown in Figure 8 and the correlation function between dp/dt in well 1 and dp/dt in well 2 is shown in Figure 9. The location of the peak in this Figure 8 is at 3600s, a measure of the correlation time T_c . The peak in Figure 9 is located at 3200s.

An estimate of the formation permeability located between wells 1 and 2 may be obtained from Equation 5 which yields 89mD and 100mD based on the respective T_c values of 3200 and 3600 where $\mu=0.001$ kg/m/s, $c=4 \times 10^{-9}$ m²N⁻¹, and r_{ij} is the distance between the wells.

$$k = \frac{\phi \mu c r_{ij}^2}{4T_c} \quad (5)$$

1 A similar analysis was performed between well 2 and 3 and the
2 peak in the correlation function was no longer reflective of the
3 formation property. The distance between these two wells is 80
4 meters and the interaction signal is dwarfed compared to the one
5 between wells 1 and 2. For example, consider a pulse in well 1
6 with no change in well 3. Because wells 2 and 3 are both 40
7 meters away from well 1, and there is no other fluctuation other
8 than that imposed in well 1, wells 2 and 3 experience a response
9 corresponding to a distance of 40 meters. These two signal
10 changes are essentially the same in both the wells and will
11 therefore have zero time displacement. Rather than have a
12 correlation function peak at $12800s \approx 80m$, a peak will appear at
13 zero. Thus, interaction between distant wells will be badly
14 affected by more dominant near-well signals. This may be
15 circumvented by looking at a targeted window correlation function
16 calculation. Taking a window around 1000s where well 1 has no
17 pulse, a correlation function based on this window is shown in
18 Figure 10. The correlation function peak now is in agreement with
19 the diffusion time scale of 12800s. Thus, any automated pulsing
20 sequence and windowing should be implemented so that the
21 observation-active well interaction is the dominant one.

22
23 Although the Example given above demonstrates the correlation
24 method between an active well and an observation point, the same

1 type of correlation can be performed between two active wells. As
2 described above, it must be ensured that only one well is pulsed
3 at a time. For the same window around 1000s, the correlation
4 function between wells 1 and 3 is shown in Figure 11. The
5 correlation function is noisy, with no discernible peak, meaning
6 that the local noise (if present) in a production well will
7 dominate over response due to distant action. If the response had
8 been ideal, a distance of 40m suggests a peak for the correlation
9 function would appear at 3200 s just as in Figure 9.

10
11 The following conclusions may be drawn based upon the above
12 numerical calculations. First, correlation functions between
13 differentiated pressure/flowrate at the source and the pressure at
14 the nearest (in the sense of pressure diffusion) observer are
15 relatively robust, and a fairly sharp peak is indicative of the
16 properties of the intervening formation. Second, the correlation
17 gets broader as the distance to the observation well increases.
18 Thus, the uncertainty increases. Third, in the presence of noise,
19 evaluation of interaction between observation wells is not
20 feasible with selective pulsing and windowing. Fourth,
21 straightforward signal processing methods that take into account
22 diffusion physics can be used in either a manual or automatic mode
23 to generate reservoir properties between two wells or zones of
24 interest. Such a table of generated values may be relayed

1 periodically from the well site(s) to the web server shown in
2 Figure 1.

3
4 There have been described and illustrated herein several
5 embodiments of methods and apparatus for remote real time oil
6 field management While particular embodiments of the invention
7 have been described, it is not intended that the invention be
8 limited thereto, as it is intended that the invention be as broad
9 in scope as the art will allow and that the specification be read
10 likewise. It will therefore be appreciated by those skilled in
11 the art that yet other modifications could be made to the provided
12 invention without deviating from its spirit and scope as so
13 claimed.